APPENDIX E

SUPPORTING INFORMATION - CONTEMPORANEOUS PROJECTS

E.1 CONTEMPORANEOUS PROJECT DESCRIPTIONS

In addition to the changes planned as part of the CXHO project, BP Whiting anticipates a number of smaller unrelated projects to occur between the time the CXHO project commences construction and reaches normal operation. Given the scope of the CXHO project, this future contemporaneous period is longer than typical and is anticipated to extend until 2011. In order to simplify the permitting process and to ensure that all predictable contemporaneous emissions increases and decreases are included in the CXHO project netting analysis, BP Whiting is including these unrelated projects as part of the CXHO permit application. These projects are described in this section. In accordance with 326 IAC 2-7-10.5(c)(2), BP Whiting is submitting a combined preconstruction and operating application. However, BP requests that IDEM issue separate approvals for authorizing construction under significant source modification regulations and operation under significant permit modification regulations.

Note that every contemporaneous project that is currently known and reasonably well-defined has been included in this section. Some of these projects were based on conservative estimates due to limited information at this time. BP may submit future modifications to these permits when more detailed information is obtained in order to gain additional emissions credits for the refinery.

In addition, there may be other projects that will need to be permitted within the contemporaneous period that are not yet well-defined or anticipated. BP will meet all requirements for netting of the CXHO Project when additional projects are proposed during the contemporaneous period.

E.1.1 BT-002 MODIFICATION

E.1.1.1 PROJECT DESCRIPTION

BP Whiting proposes to modify the existing BT-002 storage tank, located at the Marine Dock, so that it can serve as a backup tank to the existing BT-1 Marine Dock storage tank.

The BT-002 tank is currently out of service, as noted in Section D.27 of the Title V permit. While out of service, the tank had an internal floating roof installed. Thus, the tank is now equipped with a fixed roof and an internal floating roof.

The proposed modification involves bringing the BT-002 tank back into service and allowing the tank to store the same types of wastewater currently stored in BT-1. The wastewater in Tank BT-1 can contain petroleum hydrocarbons, and this mixture of water and hydrocarbon has a typical estimated maximum true vapor pressure of 2.2 psia with a maximum true vapor pressure between 1.52 and 11.1 psia.

BT-002 was constructed in 1968 and has a capacity of 874,944 gallons.

Note that since BT-002 will serve as a backup to BT-001 and, since it is located at the Marine Docks, BT-002 should be listed in Section D.34 of the Title V permit and removed from Section D.27 of the Title V permit.

E.1.1.2 EMISSION CALCULATIONS

The future potential emissions for the proposed project were calculated using USEPA Tanks 4.09d software program. The following data was used in the calculations to conservatively estimate emissions:

- Maximum estimated throughput of 26,208,000 gallons per year,
- Material properties based on hydrocarbon layer (versus bulk wastewater) and conservatively assumed to be equivalent to Gasoline with an RVP of 13 (applied for conservative emission estimation purposes and not applicability determinations), and[1]
- Detailed tank fittings and other parameters required for internal floating roof tanks.

The future potential emissions for the proposed storage tank modifications are shown below:

Source	VOC (lbs/year)	VOC (tons/year)
BT-002 Tank Emissions	1276.56	0.64

Detailed emissions calculations are provided in Appendix E.

E.1.1.3 REGULATORY APPLICABILITY

E.1.1.3.1 40 CFR PART 60 – NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The proposed change in material stored in the BT-002 storage vessel will meet the definition of a modification for the purposes of 40 CFR 60, Subpart Kb. 40 CFR 60.14(e)(5) allows the addition of use of any system or device whose primary function is the reduction of air pollutants, and 40 CFR 60.14(e)(4) allows for the use of an alternative raw material if the existing unit was designed to accommodate it under its original construction specifications. However, if a floating roof is added to a vessel as part of the switch in storage materials, the vessel is considered to be capable of accommodating the new material only if the floating roof was part of the original construction specifications for the vessel.[2] An internal floating roof was not part of the BT-002 tank's original design; therefore, the increase in emissions associated with this project would cause this tank to be modified.

[1] Note that the applicability of NSPS Kb is based on the maximum true vapor pressure as defined in 40 CFR 60.111b.

[2] See the U.S. EPA Region 5 applicability determination for Magellan Pipeline Company, LLC, dated December 2, 2004, Applicability Determine Index Control #0500014

In addition, the tank will be subject to 40 CFR 61, Subpart FF and 40 CFR 63, Subpart CC, which provide for compliance with NSPS Kb to satisfy those requirements, as described below.

E.1.1.3.2 40 CFR 61– NESHAP SUBPART FF – BENZENE WASTE OPERATIONS

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. Tank BT-001 is currently subject to 40 CFR 61, Subpart FF; therefore, Tank BT-002 will also be subject. Per 40 CFR 61.351(a)(1), the controls required by NSPS Kb will satisfy the requirements of this rule.

E.1.1.3.3 40 CFR PART 63 – NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

The BT-002 storage tank may be considered a "storage vessel" under the Refinery MACT. However, pursuant to 40 CFR 63.640(n)(1), "a Group 1 or Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section."

RULE 326 IAC 8-4-3 PETROLEUM LIQUID STORAGE FACILITIES

The BT-002 storage vessel will be subject to 326 IAC 8-4-3, as the storage capacity is greater than 39,000 gallons and the true vapor pressure of the volatile organic liquid stored will be greater than 1.52 psia. Pursuant to 326 IAC 8-4-3(b), the tank has been retrofitted with an internal floating roof, and it will be maintained so that there are no visible holes, tears, or openings in the seal or any seal fabric or materials.

RULE 326 IAC 8-9 VOLATILE ORGANIC LIQUID STORAGE VESSELS

Storage tank BT-002 is not subject to the requirements of 326 IAC 8-9 because this storage tank is subject to 40 CFR 60, Subpart Kb. Storage tanks subject to the provisions of 40 CFR 60, Subpart Kb are exempt from 326 IAC 8-9 by 326 8-9-2(8).

E.1.2 11 PIPESTILL WARP

E.1.2.1 PROJECT DESCRIPTION

The Whiting Atmospheric Relief Project (WARP) for the No. 11 Pipestill (WARP Pipestill Project) is safety driven with the intent of reducing the potential to vent hydrocarbon vapors to the atmosphere from standard unit de-inventory operations or from emergency process depressuring events.

The No. 11 Pipestill contains two atmospheric Blowdown Stacks, designated as 11PS-A and 11PS-C. The scope of this project is to install the lines and equipment necessary to re-route equipment hydrocarbon releases from discharging into these Blowdown Stacks. This equipment includes piping, new drums, pumps and cooling boxes. Hydrocarbon material will be re-directed to the existing slop system (liquid) and unit relief valves to the DDU flare header (vapor). No modifications will be made to the flare knockout drum, piping downstream, or the flare tip to accommodate the project.

The completion of this project includes the addition of fugitive components in hydrocarbon service, sewer components, and routing relief valves (RVs) to the flare header. A portion of the work has been completed for 11A Pipestill with the remaining work for 11C Pipestill to be completed at a later time. Due to this addition of fugitive components, an evaluation of the NSPS modification criteria in 40 CFR 60.14 with respect to 40 CFR 60, Subpart GGG was completed during the project's regulatory analysis. The affected facility for NSPS GGG is the group of all equipment components associated with each process unit. Thus, the group of fugitive components in 11A PS is an affected facility, and the group of components in 11C PS is the other affected facility. The 11A PS and 11C PS WARP projects resulted and will result in a VOC emissions decrease in the net emissions associated with the number of components added, removed, and controlled. As a result, these projects did not and will not result in an increase in emissions of a pollutant from an affected facility to which the NSPS applies. These projects do not qualify as modifications for NSPS GGG and are therefore not subject to 40 CFR 60, Subpart GGG.

E.1.2.2 EMISSION CALCULATIONS

E.1.2.2.1 FUGITIVES AND SEWERS

Additional fugitive components and sewers will be added as part of this project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

E.1.2.2.2 EMERGENCY FLARING EMISSIONS AT THE DDU FLARE

Nitrogen is used as a sweep gas for the vapor line going to the flare header. Only in the event of an emergency would the relief valves vent to the DDU flare. BP estimated emissions associated with emergencies. By their nature, emergency events are infrequent and unplanned. Considering these factors, BP estimated the total maximum average annual duration of emergency releases from the new tie-ins and the worst case emergency release rate scenario for new tie-ins based on current design information. This information was used to estimate the emergency release emissions. Since emissions from this portion of the projects included in this application were estimated based on projected actual emissions, actual emergency and malfunction emissions will be tracked for RVs associated with this project as applicable in accordance with Condition C.21(c) of the Title V permit or the condition as amended in the future per US EPA rulemaking regarding reasonable possibility. Refer to Appendix E for the detailed calculations.

A summary of the VOC emissions associated with these projects are provided below. Refer to the detailed calculations for a summary of the projected emergency emissions.

	VOC (tons/yr)
11A PS WARP TOTAL	2.2
11C PS WARP TOTAL	-3.9

The WARP project will not result in an increase or decrease in malfunction or emergency events. VOC emissions would have occurred from emergency and malfunction events regardless if it is routed to an atmospheric blowdown stack or flare. Therefore, VOC emissions from flaring the streams released during emergencies and malfunctions are not quantified for the WARP project since they are not increasing as a result of the WARP project. In addition, BP is not currently claiming any emissions reductions credits for controlling the VOC emissions from these events.

E.1.2.3 REGULATORY APPLICABILITY

E.1.2.3.1 40 CFR PART 60 – NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

New fugitive components installed on process equipment to re-route and service the WARP Pipestill projects will not be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG since the projects do not trigger the modification provisions of NSPS GGG and 40 CFR 60.14 as there is not an increase in VOC emissions for the affected facilities.

E.1.2.3.2 40 CFR PART 60 – NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components installed on process equipment to re-route and service the WARP Pipestill project will be subject to the Leak Detection and Repair (LDAR) requirements of 40 CFR 63, Subpart CC. Note that 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.2.3.3 40 CFR Part 60 – NSPS Subpart QQQ – VOC Emissions for Petroleum Refinery Wastewater Systems

The 11 Pipestill is currently subject to 40 CFR 60, Subpart QQQ; however, the new equipment will be exempt since it is controlled to comply with NESHAP FF.

E.1.2.3.4 40 CFR Part 60 – NSPS Subpart J – Petroleum Refineries

NSPS J regulates emissions from fuel gas combustion devices. The DDU Flare is currently subject to and will continue to be subject to the requirements for fuel gas combustion devices under NSPS J. Under these requirements, BP is required to continuously monitor the H2S concentration of the refinery fuel gas combusted in the DDU Flare to demonstrate compliance with a limitation of 0.10 gr/scf H2S in fuel gas (3-hour average). This limitation does not apply to the routing of the emergency RVs from No. 11 Pipe Still since emergencies are exempt per 40 CFR 60.104(a)(1). In addition, since nitrogen will be used as a purge gas, the purge gas will not impact compliance with 40 CFR 60, Subpart J for the DDU Flare during normal operations, including the heating value requirement per 40 CFR 60.18(c)(1)(ii).

E.1.2.3.5 40 CFR Part 61 – NESHAP Subpart FF – Benzene Waste Operations

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. The sewer equipment associated with this project will be constructed to meet these requirements as appropriate.

E.1.2.3.6 40 CFR Part 63 – MACT Subpart CC – Petroleum Refineries

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Some of the applicable components constructed as part of the WARP Pipestill project will be subject to these requirements. The new piping used to route the emergency RVs from the No. 11 Pipe Still to the existing flare header piping will be purged with nitrogen and will not be in organic HAP service during normal operations. Since the piping is not expected to be in organic HAP service for 300 hours or more per year, the equipment components for these portions of the lines are exempt from the MACT per 40 CFR 63.640(d)(3). None of the RVs tied into the flare will be considered miscellaneous process vents per 40 CFR 63, Subpart CC since RVs are exempted from the definition in 40 CFR 63.641.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.3 11C PIPESTILL TAR

During the next 11C turnaround (TAR), a number of valves will be reconditioned and pumps, piping, drums, vessels and exchangers will be cleaned and inspected and replaced in-kind if necessary. The internal trays of the fractionator towers are not currently correctly sized for unit operations, and these internals will be replaced so that the towers will run as designed and will not operate close to the operational limits. This work is being done for efficiency purposes rather than to realize an increase in unit feed rate. In addition, metallurgy upgrades will be made to some existing equipment.

Finally, a furnace improvement project will be implemented during the 11C TAR to improve process safety of the 11C process heaters, H-200 and H-300, to meet current and proposed furnace standards. The project is projected to result in reducing the pressure drop across the control valves to reduce packing leaks, reduce vibration on bypass valves and allow the option to operate the crude flash drum at pressures further below the relief valve (RV) setting. The project involves replacement of valves that control the flow of process feed to the furnaces with larger valves, but it does not impact the heat input rating of the furnaces. The project will result in the potential for more crude to be run through the furnaces at the same heat input rating; however, the project will not result in debottlenecking the 11C Pipe Still or the units downstream of 11C Pipe Still since there are other constraints at other portions of the unit that are not being impacted by any work currently planned. Furthermore, the project will not result in reconstruction of the furnaces. This information is being provided since 11C is one of the modified units for the CXHO project. No increases in emissions are included in addition to those included for the CXHO project.

E.1.4 FCU 600 WARP

The Whiting Atmospheric Relief Project (WARP) for the FCU 600 will decommission the existing blowdown stack on the unit in order to eliminate the potential to vent vapors and gases to the atmosphere from unit de-inventory operations and emergency process de-pressuring requirements. The project will install the equipment necessary (including two new drums, one new exchanger, and one new pump) to eliminate this stack and to contain and dispose of any vapors, gases, or liquids resulting from future operational or emergency requirements. All vapors and gases will be routed to the existing FCU flare. No modifications will be made to the flare knockout drum, piping downstream, or the flare tip to accommodate the project. The liquids will be collected and pumped to the existing slop system.

E.1.4.1 EMISSION CALCULATIONS

E.1.4.1.1 FUGITIVES AND SEWERS

Additional fugitive components and sewers will be added as part of the WARP project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

E.1.4.1.2 EMERGENCY FLARING EMISSIONS AT THE FCU FLARE

Only in the event of an emergency would the relief valves vent to the FCU flare. BP estimated emissions associated with emergencies. By their nature, emergency events are infrequent and unplanned. Considering these factors, BP estimated the total maximum average annual duration of emergency releases from the new tie-ins and the worst case emergency release rate scenario for new tie-ins based on current design information. This information was used to estimate the emergency release emissions. Since emissions from this portion of the projects included in this application were estimated based on projected actual emissions, actual emergency and malfunction emissions will be tracked for RVs associated with this project as applicable in accordance with Condition C.21(c) of the Title V permit or the condition as amended in the future per US EPA rulemaking regarding reasonable possibility. Refer to Appendix E for the detailed calculations.

A summary of the VOC emissions associated with this project is provided below. Refer to the detailed calculations for a summary of the projected emergency emissions.

	VOC (tons/yr)
FCU 600 WARP TOTAL	-1.5

The WARP project will not result in an increase or decrease in malfunction or emergency events. VOC emissions would have occurred from emergency and malfunction events regardless if it is routed to an atmospheric blowdown stack or flare. Therefore, VOC emissions from flaring the streams released during emergencies and malfunctions are not quantified for the WARP project since they are not increasing as a result of the WARP project. In addition, BP is not currently claiming any emissions reductions credits for controlling the VOC emissions from these events.

E.1.4.2 REGULATORY APPLICABILITY

E.1.4.2.1 40 CFR PART 60 – NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

New fugitive components installed on process equipment to re-route and service the FCU 600 WARP project will not be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG since the projects do not trigger the modification provisions of NSPS GGG and 40 CFR 60.14 as there is not an increase in VOC emissions for the affected facilities.

E.1.4.2.2 40 CFR PART 60 – NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components installed on process equipment to re-route and service the FCU 600 WARP project will be subject to the Leak Detection and Repair (LDAR) requirements of 40 CFR 63, Subpart CC. Note that 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.4.2.3 40 CFR PART 60 – NSPS SUBPART QQQ – VOC EMISSIONS FOR PETROLEUM REFINERY WASTEWATER SYSTEMS

There may be new sewers and process drain systems constructed as part of the FCU 600 WARP project that may be subject to the requirements of NSPS QQQ; however the new equipment may be exempt if it is controlled to comply with NESHAP FF. The refinery will evaluate this option during the final design specifications of the sewer system.

E.1.4.2.4 40 CFR PART 60 – NSPS SUBPART J – PETROLEUM REFINERIES

NSPS J regulates emissions from fuel gas combustion devices. The FCU Flare is not currently subject to the requirements for fuel gas combustion devices under NSPS J. The FCU Flare will not be modified as part of this project; therefore, these requirements will not apply.

E.1.4.2.5 40 CFR PART 61 – NESHAP SUBPART FF – BENZENE WASTE OPERATIONS

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. The sewer equipment associated with this project will be constructed to meet these requirements as appropriate.

E.1.4.2.6 40 CFR PART 63 – MACT SUBPART CC – PETROLEUM REFINERIES

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Some of the applicable components constructed as part of the FCU 600 WARP project will be subject to these requirements. The new piping used to route the emergency RVs from FCU 600 to the existing flare header piping may be purged with nitrogen and/or fuel gas. If nitrogen is used, it will not be in organic HAP service during normal operations. If the piping is not expected to be in organic HAP service for 300 hours or more per year, the equipment components for these portions of the lines will be exempt from the MACT per 40 CFR 63.640(d)(3). None of the RVs tied into the flare will be considered miscellaneous process vents per 40 CFR 63, Subpart CC since RVs are exempted from the definition in 40 CFR 63.641.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.5 FCU 500 TAR

During the next FCU 500 TAR, various repairs and replacements in kind will be made. The power recovery turbine will be replaced in kind, and the air ring for the catalyst regenerator will be repaired or replaced in kind, as necessary.

The power recovery turbine expander (PRT) for FCU 500 provides power to the air blower for the catalyst regenerator. It is a waste heat recovery unit that does not generate air emissions. During every TAR, it is repaired and varying amounts of parts are replaced in kind. During the FCU 500 TAR, the PRT will be replaced since the metal shell and blades are expected to be beyond repair due to normal operational erosion from catalyst and exposure to high temperatures. The capacity of the PRT will not be changed, and it will be replaced in kind, with the latest materials and fabrication methods. The PRT is a portion of the FCU regenerator system, but the replacement will not result in reconstruction of the FCU 500 regenerator since the cost is much less than the cost to install a new regenerator. The operational benefit that is projected to be realized is that there may be decreased down time for the PRT in the five-year cycle between unit TARs. There will be no increases in emissions rate for the purposes of the NSPS modification provisions in 40 CFR 60.14. Although it is projected that there will be decreased down time for the PRT as a result of this project, no additional increase in emissions is projected for FCU 500 beyond the increases projected for the CXHO project. Additional increases are not projected since projected increases in feed rates at the FCUs for the CXHO project are greater than the projected increases that may be realized due to the decrease in downtime. In addition, FCU 500 is capable of operating, albeit at a lower feed rate, without the PRT, and this project does not affect the capacity or potential to emit of FCU 500. This project will not extend the life of the FCU catalyst regenerator or FCU 500 since it will not modify the FCU catalyst regenerator, air blower, or the FCU 500 unit itself. This information has been provided since the FCU 500 is one of the affected units for the CXHO project.

During the FCU 500 TAR, the air ring for the catalyst regenerator will be inspected. Repairs to the ring will be conducted as necessary, or the air ring will be replaced in kind if it is too difficult to repair. The capacity of the air ring will not change and the catalyst regenerator will not be reconstructed if it is replaced in kind. In addition, there will be no emissions increase; therefore, the catalyst regenerator will not be modified for the purposes of 40 CFR 60, Subpart J.

The VRU-100 and VRU-200, which process wet gasoline/gasoline from the E-1 Fractionator will also be reviewed and possibly modified. This could include tower retrays, increasing existing pump and cooling capacities and equipment velocity studies for all VRU equipment and exchangers.

E.1.6 FCU 500 WARP

E.1.6.1 PROJECT DESCRIPTION

During the next FCU 500 TAR, the atmospheric blowdown stack will be eliminated. WARP for the FCU 500 is safety driven with the intent of reducing the potential to vent hydrocarbon vapors to the atmosphere from standard unit de-inventory operations or from emergency process depressuring events. BP will decommission the existing blowdown stack on the unit in order to eliminate the potential to vent vapors and gases to the atmosphere from unit de-inventory operations and emergency process de-pressuring requirements. The project will install the equipment necessary to eliminate this stack. The new equipment will contain vapors, gases, or liquids resulting from future operational or emergency requirements. Vapors and gases not contained will be routed to the existing VRU flare. No modifications will be made to the flare knockout drum, piping downstream, or the flare tip to accommodate the project. The liquids will be collected and pumped to the existing slop system. Since this project is in the earlier stages of planning, the FCU 600 WARP information was used to estimate the emissions associated with the project. In addition, no credit is currently taken for decommissioned components. This information will be provided when available, but the refined information is expected to result in emissions decreases from the values presented in this application.

E.1.6.2 EMISSION CALCULATIONS

E.1.6.2.1 FUGITIVES AND SEWERS

Additional fugitive components and sewers will be added as part of this project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

E.1.6.2.2 EMERGENCY FLARING EMISSIONS AT THE VRU FLARE

Only in the event of an emergency would the relief valves vent to the VRU flare. BP estimated emissions associated with emergencies. By their nature, emergency events are infrequent and unplanned. Considering these factors, BP estimated the total maximum average annual duration of emergency releases from the new tie-ins and the worst case emergency release rate scenario for new tie-ins based on current design information. This information was used to estimate the emergency release emissions. Since emissions from this portion of the projects included in this application were estimated based on projected actual emissions, actual emergency and malfunction emissions will be tracked for RVs associated with this project as applicable in accordance with Condition C.21(c) of the Title V permit or the condition as amended in the future per US EPA rulemaking regarding reasonable possibility. Refer to Appendix E for the detailed calculations.

A summary of the estimated VOC emissions associated with this project is provided below. Refer to the detailed calculations for a summary of the projected emergency emissions.

	VOC (tons/yr)
TOTAL	1.0

The WARP project will not result in an increase or decrease in malfunction or emergency events. VOC emissions would have occurred from emergency and malfunction events regardless if it is routed to an atmospheric blowdown stack or flare. Therefore, VOC emissions from flaring the streams released during emergencies and malfunctions are not quantified for the WARP project since they are not increasing as a result of the WARP project. In addition, BP is not currently claiming any emissions reductions credits for controlling the VOC emissions from these events.

E.1.6.3 REGULATORY APPLICABILITY

E.1.6.3.1 40 CFR PART 60 – NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

A formal analysis has not yet been conducted, but it is suspected that the WARP project will not trigger a modification for NSPS GGG based on the analyses for the other WARP projects in accordance with 40 CFR 60.590(c) and 40 CFR 60.14. Other WARP projects will result in a VOC emissions decrease in the net emissions associated with the number of components added, removed, and controlled. As a result, these projects did not and will not result in an increase in emissions of a pollutant from an affected facility to which the NSPS applies. It is expected that the FCU 500 WARP project will also result in a decrease in emissions from the affected facility and not qualify as a modification for NSPS GGG. Therefore, the unit is not subject to 40 CFR 60, Subpart GGG as a result of this project.

E.1.6.3.2 NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components in light or heavy liquid service that are installed as part of this project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG and/or 40 CFR 63, Subpart CC. Note that NSPS GGG and 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.6.3.3 40 CFR Part 60 – NSPS Subpart QQQ – VOC Emissions for Petroleum Refinery Wastewater Systems

FCU 500 is currently subject to 40 CFR 60, Subpart QQQ; however the new equipment may be exempt if it is controlled to comply with NESHAP FF. The refinery will evaluate this option during the final design specifications of the sewer system .

E.1.6.3.4 40 CFR Part 60 – NSPS Subpart J – Petroleum Refineries

NSPS J regulates emissions from fuel gas combustion devices. The VRU Flare is not currently subject to the requirements for fuel gas combustion devices under NSPS J. The VRU Flare will not be modified as part of this project; therefore, these requirements will not apply.

E.1.6.3.5 40 CFR Part 61 – NESHAP Subpart FF – Benzene Waste Operations

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. The sewer equipment associated with this project will be constructed to meet these requirements as appropriate.

E.1.6.3.6 40 CFR Part 63 – MACT Subpart CC – Petroleum Refineries

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Some of the applicable components constructed as part of the FCU 500 WARP project will be subject to these requirements. The new piping used to route the emergency RVs from FCU 500 to the existing flare header piping may be purged with nitrogen and, if nitrogen is used, it will not be in organic HAP service during normal operations. If the piping is not expected to be in organic HAP service for 300 hours or more per year, the equipment components for these portions of the lines will be exempt from the MACT per 40 CFR 63.640(d)(3). None of the RVs tied into the flare will be considered miscellaneous process vents per 40 CFR 63, Subpart CC since RVs are exempted from the definition in 40 CFR 63.641.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.7 VRU 100/200 WARP

E.1.7.1 PROJECT DESCRIPTION

During the last VRU 100/200 TAR, a WARP project was implemented to reroute the relief valves (RVs) that vented to the atmospheric blowdown stack to the VRU flare. WARP for VRU 100/200 was safety driven with the intent of reducing the potential to vent hydrocarbon vapors to the atmosphere from standard unit de-inventory operations or from emergency process depressuring events.

The scope of this project was to install the lines and equipment necessary to re-route equipment hydrocarbon releases from discharging into the blowdown stack. Hydrocarbon material will be re-directed to the existing slop system (liquid) and unit relief valves to the VRU flare header (vapor). No modifications will be made to the flare knockout drum, piping downstream, or the flare tip to accommodate the project.

The completion of this project included the addition of fugitive components in hydrocarbon service, sewer components, and routing RVs to the flare header. Due to this addition of fugitive components, an evaluation of the NSPS modification criteria in 40 CFR 60.14 with respect to 40 CFR 60, Subpart GGG was completed during the project's regulatory analysis. The affected facility for NSPS GGG is the group of all equipment components associated with each process unit. Thus, the group of components associated with VRU 100 is an affected facility, and the group of components associated with the VRU 200 is an affected facility. The VRU 100/200 WARP project resulted in a VOC emissions decrease in the net emissions associated with the number of components added, removed, and controlled at each unit. As a result, this project did not result in an increase in emissions of a pollutant from an affected facility to which the NSPS applies. This project does not qualify as a modification for NSPS GGG and is therefore not subject to 40 CFR 60, Subpart GGG.

E.1.7.2 EMISSION CALCULATIONS

E.1.7.2.1 FUGITIVES AND SEWERS

Additional fugitive components and sewers will be added as part of this project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

E.1.7.2.2 EMERGENCY FLARING EMISSIONS AT THE VRU FLARE

Nitrogen is used as a sweep gas for the vapor line going to the flare header. Only in the event of an emergency would the relief valves vent to the VRU flare. BP estimated emissions associated with emergencies. By their nature, emergency events are infrequent and unplanned. Considering these factors, BP estimated the total maximum average annual duration of emergency releases from the new tie-ins and the worst case emergency release rate scenario for new tie-ins based on current design information. This information was used to estimate the emergency release emissions. Since emissions from this portion of the projects included in this application were estimated based on projected actual emissions, actual emergency and malfunction emissions will be tracked for RVs associated with this project as applicable in accordance with Condition C.21(c) of the Title V permit or the condition as amended in the future per US EPA rulemaking regarding reasonable possibility. Refer to Appendix E for the detailed calculations.

A summary of the VOC emissions associated with this project is provided below. Refer to the detailed calculations for a summary of the projected emergency emissions.

	VOC (tons/yr)
TOTAL	-0.2

The WARP project will not result in an increase or decrease in malfunction or emergency events. VOC emissions would have occurred from emergency and malfunction events regardless if it is routed to an atmospheric blowdown stack or flare. Therefore, VOC emissions from flaring the streams released during emergencies and malfunctions are not quantified for the WARP project since they are not increasing as a result of the WARP project. In addition, BP is not currently claiming any emissions reductions credits for controlling the VOC emissions from these events.

E.1.7.3 REGULATORY APPLICABILITY

E.1.7.3.1 40 CFR PART 60 – NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

New fugitive components installed to re-route and service the VRU 100/200 WARP project will not be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG since the project does not trigger the modification provisions of NSPS GGG and 40 CFR 60.14 as there is not an increase in VOC emissions for the affected facilities.

E.1.7.3.2 40 CFR PART 60 – NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components installed to re-route and service the VRU 100/200 WARP project will be subject to the Leak Detection and Repair (LDAR) requirements of 40 CFR 63, Subpart CC. Note that 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.7.3.3 40 CFR PART 60 – NSPS SUBPART QQQ – VOC EMISSIONS FOR PETROLEUM REFINERY WASTEWATER SYSTEMS

VRU 100 and 200 are currently subject to 40 CFR 60, Subpart QQQ; however, the new equipment is exempt since it is controlled to comply with NESHAP FF.

E.1.7.3.4 40 CFR PART 60 – NSPS SUBPART J – PETROLEUM REFINERIES

NSPS J regulates emissions from fuel gas combustion devices. The VRU Flare is not currently subject to the requirements for fuel gas combustion devices under NSPS J. The VRU Flare will not be modified as part of this project; therefore, these requirements will not apply.

E.1.7.3.5 40 CFR PART 61 – NESHAP SUBPART FF – BENZENE WASTE OPERATIONS

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. The sewer equipment associated with this project will be constructed to meet these requirements as appropriate.

E.1.7.3.6 40 CFR PART 63 – MACT SUBPART CC – PETROLEUM REFINERIES

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Some of the applicable components constructed as part of the VRU 100/200 WARP project will be subject to these requirements. The new piping used to route the emergency RVs from VRU 100/200 to the existing flare header piping will be purged with nitrogen and will not be in organic HAP service during normal operations. Since the piping is not expected to be in organic HAP service for 300 hours or more per year, the equipment components for these portions of the lines are exempt from the MACT per 40 CFR 63.640(d)(3). None of the RVs tied into the flare will be considered miscellaneous process vents per 40 CFR 63, Subpart CC since RVs are exempted from the definition in 40 CFR 63.641.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.8 FIRE PUMP ENGINES

E.1.8.1 PROJECT DESCRIPTION

BP Whiting proposes to install three (3) new fire pump engines rated at 390 horsepower (Hp) each. The fire pump engines will be emergency engines that will only be used during regular testing activities and during emergencies, if necessary. The fire pump engines will be exempt per 326 IAC 2-1.1-3(e)(25)(C) and insignificant activities per 326 IAC 2-7-1(21)(G)(xxii)(CC).

E.1.8.2 EMISSION CALCULATIONS

The future potential emissions for the proposed project were calculated using a combination of emission factors from EPA's AP-42 Table 3.3-1 for diesel-fired industrial engines, Section 3.3 (October 1996) and the applicable enforceable NSPS IIII limits. In addition, the sulfur emissions were estimated based on the current sulfur standard for diesel fuel. The engines may be purchased and installed as early as 2008; therefore, the NSPS IIII limits associated with model year 2008 engines were considered for the purposes of determining enforceable emissions limits and emissions factors. If later model year engines are purchased, the emissions will be lower than those estimated. Since the engines are emergency engines, it was assumed that the engines will each only operate for a maximum of 500 hours per year. The future potential emissions for the proposed engines are provided in Appendix E and are summarized below.

Pollutant	**NO_X**	**SO_2**	**PM**	**$PM_{10}/PM_{2.5}$**	**CO**	**VOC**
Project Emissions Increase (tpy)	**5.0**	**0.1**	**0.3**	**0.3**	**1.7**	**0.7**

E.1.8.3 REGULATORY APPLICABILITY

NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines
40 CFR 60, Subpart IIII (NSPS) regulates emissions from stationary compression ignition internal combustion engines constructed after July 11, 2005. The three fire pump engines will be manufactured after July 11, 2005, therefore they will be subject to NSPS IIII. Per 40 CFR 60.4205(c), BP will be required to meet a NO_x and non-methane hydrocarbons (NMHC) limit of 7.8 grams per brake horsepower-hour (g/bhp-hr), a CO limit of 2.6 g/bhp-hr, and a PM limit of 0.40 g/bhp-hr. In addition, in accordance with 40 CFR 80.510(a), the engines will have a fuel sulfur limit of 500 ppm until June 1, 2010, when the fuel sulfur limit will drop to 15 ppm. BP will be required to install a non-resettable hour meter on each engine per 40 CFR 60.4209(a). Compliance with the emission limits will be demonstrated through the manufacturer's certification that the fire pump engines will meet the emission required limits at the National Fire Protection Association (NFPA) nameplate engine power.

E.1.8.3.1 40 CFR 63, Subpart ZZZZ – Stationary internal Combustion Engine

40 CFR 63 Subpart ZZZZ contains National Emission Standards for Hazardous Air Pollutants (NESHAP) for reciprocating engines. BP is a major source of HAPs with respect to the thresholds defined in Section 112(b) of the Act. 40 CFR 63.6590(a) defines the affected sources to which Subpart ZZZZ applies, as follows:

An affected source is any existing, new, or reconstructed stationary RICE with a site-rating of more than 500 brake horsepower located at a major source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.
Since each fire pump engine has a site-rating of less than 500 brake horsepower, 40 CFR 63 Subpart ZZZZ does not apply to the fire pump engines.

E.1.8.3.2 326 IAC 5-1-2 – Opacity Limits

This rule requires facilities in Lake County to meet the following facility-wide opacity limits:

Opacity shall not exceed 20% in any six-minute period, and
Opacity shall not exceed 60% in any cumulative total of fifteen (15) minutes is any 6-hour average period.

The three fire pump engines are subject, and will comply, with the opacity limits in this rule.

E.1.8.3.3 326 IAC 6.8-1-2 –Particulate Limits

The three fire pump engines will be subject to the provisions of this rule, specifically paragraph (a), which limits PM emissions to 0.03 grains per dry standard cubic foot (gr/dscf). The engines will comply with this rule.

E.1.8.3.4 326 IAC 7-4.1-1–SO_2 Emission Limitations

The three fire pump engines will not be subject to the limitations per 326 IAC 7-4.1-1 since the potential SO_2 emissions from these units are below the 25 tpy applicability threshold specified in 326 IAC 7-1.1-1.

E.1.8.3.5 326 IAC 8-1-6 – VOC Rules, Best Available Control Technology (BACT)

In this rule, IDEM requires every new unit that has potential emissions greater than 25 tpy of VOC to perform a BACT review. Since the fire pump engines do not have potential emissions greater than 25 tpy of VOC, this rule is not applicable.

E.1.8.3.6 326 IAC 10-4-2 –NO_X BUDGET TRADING PROGRAM

The NO_x Budget Trading Program is applicable to large affected units. The fire pump engines do not qualify as large affected units, therefore this rule is not applicable.

E.1.9 DEWATERING AND THERMAL DESORPTION

E.1.9.1 PROJECT DESCRIPTION

BP Whiting proposes to replace the existing dewatering and sludge processing system, located at the Waste Water Treatment Plant (WWTP). The existing dewatering system and fluidized bed incinerator (FBI) will be shut down and a new dewatering and thermal desorption system will be installed.

The dewatering system will receive various sludges produced at the refinery, such as dissolved air flotation (DAF) skimmings and API oil/water separator sludge, via a closed pump system from existing sludge handling tanks. A diluted polymer will be injected as a coagulant in-line prior to the dewatering system. In addition, steam may also be injected in the line prior to the dewatering system to improve the operation of the dewatering system. The dewatering system will be a completely enclosed system consisting of the following equipment: two (2) centrifuges, two (2) sludge surge tanks, one centrate (e.g., oil/water mixture) surge tank, an enclosed auger transfer system, and fugitive components (e.g., pumps, valves, flanges, etc.). Vents from the system will be routed to a closed vent system and wet scrubber and carbon canister system for control of emissions. The scrubbing liquid will contain various additives that will optimize absorption of hydrocarbons. The vapors may be routed to the thermal desorption burners for treatment in the event that the scrubber and carbon canister system is shut down for maintenance.

The sludge will be processed through the centrifuges and then routed to one of the surge tanks and then to the thermal desorption system via the enclosed auger system. The recovered oil and water will be routed from the centrifuges to a surge tank to existing refinery tanks where the oil will be recovered and the water will be decanted to the closed process sewer system. The dewatering system capacity depends on the composition of the sludge being processed, will vary based on the solids content of the sludge being processed, and will also be limited by the thermal desorption unit capacity for sludges that are processed by both systems.

The thermal desorption system will consist of a rotating drum that is heated externally with two diesel-fired burners rated at 4 MMBtu/hr each. The waste is conveyed through the drum in an oxygen-starved environment, using an inert sweep gas such as nitrogen or steam. The heat will volatilize the water and hydrocarbons which will be swept at the feed end of the drum to a vapor recovery system. The solids will exit at the opposite end of the drum to an enclosed mixing auger rehydration system and are not expected to have appreciable concentrations of hydrocarbons. The auger rehydration system will be vented to a wet scrubber to capture any dust emissions. The rehydrated solids will then be transferred to roll-off containers for transportation to final disposal.

The vapor recovery system will consist of an oil condensing/scrubbing system, a water condensing/scrubbing system, and an oil/water separator. The oil condensing/scrubbing phase is designed to remove components that condense at or above approximately 240 degrees Fahrenheit (F). The water condensing/scrubbing phase is designed to remove components that condense between approximately 240 degrees F and 150 degrees F. The condensed oil and water will be recirculated through their associated vessels and slip streams will be removed as the vessel levels rise. The recovered oil will be routed to an existing dirty gas oil (DGO) tank or directly back to one of the pipe stills. The recovered water will be routed to the existing sewer system. A non-contact heat exchanger will be used to cool the condensed oil and water. An enclosed oil/water separator will be used as part of the water quench loop to remove any oil recovered in the water condensing phase. The oil and water will be routed to existing refinery systems as described above. The noncondensible vapors from this system (i.e., any portion of the volatilized material that will not condense at 150 degrees F) will be routed to the thermal desorption burners for destruction of the majority of the remaining hydrocarbons. These vapors are expected to consist of the inert sweep gas and light hydrocarbons such as methane and propane.

The thermal desorption system will have a design capacity of 9,000 dry tons of solids per year.

E.1.9.2 EMISSION CALCULATIONS

The future potential emissions for the dewatering system and thermal desorption system were estimated based on mass balances, proposed system design characteristics, emission factors from EPA's AP-42 Section 1.3 (September 1998), and emission factors from EPA's AP-42 Section 1.4 (July 1998). To estimate the VOC emissions increase due to the new fugitive emission components, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. As detailed in Appendix C (Tables C.29 through C.43 and C.63), the gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for pumps and valves are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv leak definition for pumps. The remainder of the new fugitive components achieve a 30% control efficiency from audio/visual/olfactory observations (AVO) per Texas Commission on Environmental Quality (TCEQ) Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000). The assumptions used in the emissions calculations are documented in the detailed calculations provided in Appendix E.

The future potential emissions for the proposed dewatering and thermal desorption projects are provided in Appendix E and are shown below:

	VOC (tons/yr)	NO_x (tons/yr)	PM (tons/yr)	$PM_{10}/PM_{2.5}$ (tons/yr)	CO (tons/yr)	SO_2 (tons/yr)
Dewatering Emissions	0.9	n/a	n/a	n/a	n/a	n/a
Thermal Desorption Emissions (Burners and VOC)	0.9	5.2	0.5	0.8	1.3	1.8
Fugitive Equipment Components	0.6	n/a	n/a	n/a	n/a	n/a
TOTAL	2.4	5.2	0.5	0.8	1.3	1.8

E.1.9.3 REGULATORY APPLICABILITY

E.1.9.3.1 NSPS SUBPART J – PETROLEUM REFINERIES

NSPS J regulates emissions from fuel gas combustion devices, fluidized catalytic cracking units and sulfur recovery units. The thermal desorption unit burners will be subject to the requirements for fuel gas combustion devices under NSPS J since the noncondensible vapors from the system will be routed through the burners. Under these requirements, BP will be required to continuously monitor the H_2S concentration of the fuel gas combusted in these burners to demonstrate compliance with a limitation of 0.1 gr/scf H_2S in fuel gas (3-hour average) or to apply for an Alternative Monitoring Plan (AMP).

E.1.9.3.2 NSPS SUBPART QQQ – VOC EMISSIONS FOR PETROLEUM REFINERY WASTE WATER SYSTEMS

There may be new process drain systems and there will be an oil/water separator constructed as part of this project that may be subject to the requirements of NSPS QQQ; however the new equipment may be exempt if it is controlled to comply with NESHAP FF. The refinery will evaluate this option during the final design specifications of the sewer system.

E.1.9.3.3 NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components in light or heavy liquid service that are installed as part of this project may be subject to the Leak Detection and Repair (LDAR) requirements of NSPS VV per 40 CFR 63, Subpart CC.

E.1.9.3.4 40 CFR 61, SUBPART FF – BENZENE WASTE OPERATIONS

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. Construction of this project may alter existing benzene waste streams. BP will be required to update the TAB, and install additional controls, as appropriate and required.

E.1.9.3.5 40 CFR 61, SUBPART E – NATIONAL EMISSION STANDARD FOR MERCURY

The thermal desorption system will be used to dry sludge; however, it is not a sludge dryer as defined by 40 CFR 61.51(m) since it will not be a device used to reduce the moisture content of sludge by heating to temperatures above 65°C (ca. 150°F) directly with combustion gases. The sludge will be indirectly heated with combustion gases.

E.1.9.3.6 40 CFR 61, SUBPART J - NATIONAL EMISSION STANDARD FOR EQUIPMENT LEAKS (FUGITIVE EMISSION SOURCES) OF BENZENE

Since the existing WWTP systems are not subject to these requirements, it is not expected that the dewatering and thermal desorption system will have equipment in benzene service per 40 CFR 61.111.

E.1.9.3.7 40 CFR 63, SUBPART CC – PETROLEUM REFINERIES

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements, control and monitoring requirements for wastewater, storage tanks and process vents. Applicable units constructed as part of this project will also be subject to these requirements. Note that an affected facility under 40 CFR 63 Subpart CC is defined as the entire refinery, therefore, this project will not constitute a "reconstruction" of the affected source. As such, new units constructed as part of this project will be subject to the same existing source standards already applicable to the refinery.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.9.3.8 40 CFR 63, SUBPART EEE – HAZARDOUS WASTE COMBUSTORS

The thermal desorption system is not regulated by 40 CFR 63, Subpart EEE since the system does not burn hazardous waste per the definition of hazardous waste combustor or incinerator in 40 CFR 63.1201.

E.1.9.3.9 40 CFR 63, SUBPART DDDDD – INDUSTRIAL COMMERCIAL, AND INDUSTRIAL BOILERS AND PROCESS HEATERS

The regulations of 40 CFR 63, Subpart DDDDD have been vacated as of the time of submission of this application. IDEM has not adopted an interim regulation, and therefore the requirements of 40 CFR 63, Subpart DDDDD are not addressed in this application. Once a replacement regulation is promulgated, the burners will be evaluated for applicability with respect to the replacement regulation to 40 CFR 63, Subpart DDDDD.

E.1.9.3.10 326 IAC 4-2 INCINERATORS

The thermal desorption unit is not an incinerator as defined by 326 IAC 1-2-34 since it is not designed to burn waste substances. The system is designed to heat waste substances to remove and recover volatile materials.

E.1.9.3.11 326 IAC 6.8-1-2 PARTICULATE LIMITS

The thermal desorption system will be subject to the provisions of this rule, specifically paragraph (a), which limits PM emissions to 0.03 grains per dry standard cubic foot (gr/dscf).

E.1.9.3.12 326 IAC 7-4.1-1–SO_2 EMISSION LIMITATIONS

The thermal desorption system will not be subject to the limitations per 326 IAC 7-4.1-1 since the potential SO_2 emissions from this unit are below the 25 tpy and 10 lb/hr applicability threshold specified in 326 IAC 7-1.1-1

E.1.9.3.13 RULE 326 IAC 8-4-2 REFINING SOURCES

The oil/water separator will be subject to 326 IAC 8-4-2(2).

E.1.9.3.14 RULE 326 IAC 8-4-3 PETROLEUM LIQUID STORAGE FACILITIES AND RULE 326 IAC 8-9 VOLATILE ORGANIC LIQUID STORAGE VESSELS

The new liquid vessels that will be installed as part of the project are not designed to be storage vessels; therefore, they are not subject to the requirements of 326 IAC 8-4-3 and 326 IAC 8-9.

E.1.9.3.15 RULE 326 IAC 8-4-8 REFINERY MONITORING PROGRAMS

Portions of the fugitive components associated with the dewatering and thermal desorption systems will be subject to the Leak Detection and Monitoring Requirements (LDAR) in 326 IAC 8-4-8.

E.1.9.3.16 RULE 326 IAC 8-7 SPECIFIC VOC REDUCTION REQUIREMENTS FOR LAKE, PORTER, CLARK, AND FLOYD COUNTIES

The dewatering and thermal desorption system will not be subject to 326 IAC 8-7 per 326 IAC 8-7-2(a)(2)(B) since the system is part of the WWTP, and the WWTP is not an industrial wastewater treatment plant as defined by 326 IAC 8-7-1(6).

E.1.9.3.17 RULE 326 IAC 8-1-6 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

This rule is not applicable to the dewatering and thermal desorption systems since portions of the systems are subject to other requirements in 326 IAC 8. In addition, the dewatering system does not have potential emissions greater than 25 tons per year. Furthermore, the air pollution control equipment is necessary in order to comply with federal regulations such as 40 CFR 61, Subpart FF, 40 CFR 63, Subpart CC, and 40 CFR 60, Subpart QQQ and will be integral to the normal operation of each facility.

E.1.10 TANK 8 OIL WATER SEPARATOR REPLACEMENT

E.1.10.1 PROJECT DESCRIPTION

BP Whiting proposes to install a new or redundant oil/water separator system to replace or provide an alternate for the existing Tank 8 that is used to treat process and rainwater at 11 Pipe Still. The final system design has not yet been determined; however, the design being considered that is estimated to have the highest potential to emit is conservatively included in this application. The existing Tank 8 will not be replaced immediately; therefore, no emissions reductions credits are being considered at this time for the shutdown of the existing Tank 8.

The design being considered for the purposes of this application is a closed oil/water separation system that is vented to a carbon canister for control in accordance with applicable requirements of 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF. The oil/water separator will be designed for a maximum average flow rate of 100,000 gallons per day. In addition, associated fugitive components will also be added.

E.1.10.2 EMISSION CALCULATIONS

The future potential emissions for Tank 8 system were estimated with emission factors from EPA's AP-42 Section 5.1 (January 1995). To estimate the VOC emissions increase due to the new fugitive emission components, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. As detailed in Appendix C (Tables C.29 through C.43 and C.63), the gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for pumps and valves are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv leak definition for pumps. The remainder of the new fugitive components achieve a 30% control efficiency from audio/visual/olfactory observations (AVO) per Texas Commission on Environmental Quality (TCEQ) Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000). The assumptions used in the emissions calculations are documented in the detailed calculations provided in Appendix E.

The future potential emissions for the proposed new/redundant Tank 8 are provided below:

	VOC (tons/yr)
Tank 8	3.7
Fugitive Equipment Components	2.4
TOTAL	6.1

E.1.10.3 Regulatory Applicability

E.1.10.3.1 NSPS Subpart QQQ – VOC Emissions for Petroleum Refinery Wastewater Systems

The 11 Pipe Still is currently subject to NSPS QQQ. There may be new process drain systems, junction boxes, and/or a manhole installed as part of this project. There will be an oil/water separator constructed as part of this project that may be subject to the requirements of NSPS QQQ; however the new equipment may be exempt if it is controlled to comply with NESHAP FF. The refinery will evaluate this option during the final design specifications of the sewer system.

E.1.10.3.2 40 CFR Part 60 – NSPS Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries

A formal analysis has not yet been conducted to determine if this project will trigger a modification for NSPS GGG in accordance with 40 CFR 60.590(c) and 40 CFR 60.14. The project scope has not yet been completely defined, and this permit application includes the current option being considered with the maximum impact on emissions. A more detailed regulatory applicability analysis will be conducted as part of the permit review process.

E.1.10.3.3 NSPS Subpart VV – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

New fugitive components in light or heavy liquid service that are installed as part of this project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG and/or 40 CFR 63, Subpart CC. Note that NSPS GGG and 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.10.3.4 40 CFR 61, Subpart FF – Benzene Waste Operations

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. BP will be required to update the TAB, and install controls for the oil/water separator and any drains, as appropriate and required.

E.1.10.3.5 40 CFR 63, Subpart CC – Petroleum Refineries

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements, control and monitoring requirements for wastewater, storage tanks and process vents. Applicable units constructed as part of this project will also be subject to these requirements. Note that an affected facility under 40 CFR 63 Subpart CC is defined as the entire refinery, therefore, this project will not constitute a "reconstruction" of the affected source. As such, new units constructed as part of this project will be subject to the same existing source standards already applicable to the refinery.

In addition, per 40 CFR 63.640(o)(1), any new equipment in Group 1 wastewater service is exempt from NSPS QQQ if it is controlled under NESHAP subpart FF.

E.1.10.3.6 Rule 326 IAC 8-4-2 Refining Sources

The oil/water separator will be subject to 326 IAC 8-4-2(2).

E.1.10.3.7 Rule 326 IAC 8-4-8 Refinery Monitoring Programs

The fugitive components associated with the oil/water separation system will be subject to the Leak Detection and Monitoring Requirements (LDAR) in 326 IAC 8-4-8.

E.1.11 Boilers

E.1.11.1 Project Description

As discussed in Section 2.2, two new boilers will be constructed. Each of the boilers will be rated at 580 MMBtu/hr. BP is requesting an annual limit on total fuel input for both boilers at 97.5% of the total combined heat input capacity (i.e., 9,907,560 MMBtu/yr) to allow flexibility for maintenance outages.

The two new boilers will be equipped with Low NO_X Burners and possibly Selective Catalytic Reduction (SCR) for control of NO_X emissions; therefore, collateral emissions for the SCRs have conservatively been included in this application. Since the boilers will be constructed before the refinery fuel gas treatment system consistently provides refinery fuel gas with a total reduced sulfur (TRS) content of 80 ppmv, the boilers will either blend natural gas with refinery fuel gas or control the TRS in the fuel gas separately in the interim period and, if necessary, after the refinery fuel gas TRS content is reduced by the CXHO project such that the potential SO_2 emissions from each boiler will be below 25 tpy. BP will install a TRS CEMS for the new boilers to determine compliance with the SO_2 limit based on TRS input.

Fugitive components for the fuel gas system will also be added to supply fuel gas to the boilers as part of this project.

A simplified process flow diagram is provided in Appendix E.

E.1.11.2 EMISSIONS CALCULATIONS

E.1.11.2.1 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

The annual VOC emissions from combustion for the boilers are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) as is presented in the equation below.[3]

$$Emissions(tpy) = D * VOC\ EF_{AP-42} * \frac{1}{HHV_{AP-42}} * 8{,}760\ \frac{hr}{yr} * \frac{1\ ton}{2{,}000\ lb}$$

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
VOC EF_{AP-42} = AP-42 emission factor (lb/MMscf)
HHV_{AP-42} = natural gas higher heating value assumed by AP-42 (MMBtu/MMscf)

An overall utilization factor of 97.5% is applied to calculate the limited annual potential emissions for both boilers. Detailed emission calculations are provided in the emission calculations sheet provided in Appendix F.

E.1.11.2.2 NITROGEN OXIDE (NO_X) AND CARBON MONOXIDE (CO) EMISSIONS

The NO_X and CO emissions for the new boilers are based on vendor guaranteed emission rates. These are detailed in the table below.

NO_X AND CO EMISSION RATES

Unit	NO_X Emission Rate (lb/MMBtu)	NO_X Control	CO Emission Rate (lb/MMBtu)	CO Control
Boilers	0.065	Controlled – Low NO_X Burners and/or SCR	0.024	Good Combustion Practices

The methodology to calculate NO_X and CO emissions is presented in the equation below.

$$NO_X\ \ Emissions(tpy) = D * NO_X\ \ EF * 8{,}760\ \frac{hr}{yr} * \frac{1\ ton}{2{,}000\ lb}$$

[3] Process heaters at the BP Whiting refinery fire mainly refinery fuel gas. Refinery fuel gas is very similar in composition to natural gas, with the possible exception of its sulfur content. AP-42 emission factors for natural gas combustion are a good representation of refinery fuel gas combustion emissions for all criteria pollutants except SO_2 and it is common practice in the refining industry to utilize these factors.

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
NO_x EF = NO_x emission factor (lb/MMBtu)
An overall utilization factor of 97.5% is applied to calculate the limited annual potential emissions for both boilers.

E.1.11.2.3 SULFUR DIOXIDE (SO_2) EMISSIONS

SO_2 emissions from the boilers can be calculated using the equation below.

$$SO_2 \ Emissions(tpy) = D * SO_2 \ EF * \frac{1}{HHV_F} * 8{,}760 \frac{hr}{yr} * \frac{1\,ton}{2{,}000\,lb}$$

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
HHV_F = Higher heating value of blended refinery fuel gas and natural gas (MMBtu/MMscf)
SO_2 EF = SO_2 emission factor (lb/MMscf)
An overall utilization factor of 97.5% is applied to calculate the limited annual potential emissions for both boilers.

The emission factor (SO_2 EF) in the above equation is a function of the total sulfur concentration in the blended fuel gas and natural gas and can be calculated from the Ideal Gas Law as follows:

$$SO_2 \ EF = \frac{C * MW * P}{R * T}$$

Where,
C = Blended refinery fuel gas and natural gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft^3/(lbmol*R))
T = Temperature (R)

As part of the boilers project, the maximum total sulfur content in the fuel gas is projected to be no more than the concentration that results in potential emissions less than 25 tpy for each boiler (approximately 79 ppmv). It is assumed that 1 mole of sulfur compounds in the fuel gas will yield 1 mole of SO_2 emissions. Therefore, a sample SO_2 emission factor can be calculated in accordance with the equation below:

$$SO_2\ EF = (80\ ppm) * (\frac{1\, lbmol\ SO_2}{1\, lbmol\ total\ sulfur}) * (\frac{64.06\, lb\ SO_2}{1\, lbmol\ SO_2}) * \frac{14.7\ psi}{(10.73\ \frac{psi \cdot ft^3}{lbmol \cdot R}) * (67.7 + 460)^o R}$$

$$SO_2\ EF = 13.30\ \frac{lb\ SO_2}{MMscf}$$

The projected future actual annual average fuel gas higher heating value is 1203.3 MMBtu/MMscf. The blended fuel gas and natural gas higher heating value is approximately 1108 MMBtu/MMscf.

Note that, for the purpose of estimating SO_2 emissions, BP is assuming that all sulfur oxides are emitted in the form of SO_2.[4] This assumption is conservative, since, as discussed below, as much as 3% of the total sulfur oxides emitted will be in the form of SO_3 , which will be emitted as either condensable PM or sulfuric acid mist.

E.1.11.2.4 PARTICULATE MATTER ($PM/PM_{10}/PM_{2.5}$) EMISSIONS

The combustion-related $PM_{10}/PM_{2.5}$ emissions for the boilers are calculated using the total PM emission factor from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). The PM emissions are calculated using the filterable PM emission factor.

For example, the annual $PM_{10}/PM_{2.5}$ emissions from the boilers are calculated as follows:

$$PM_{10} / PM_{2.5} = Heat\ Input\ \frac{MMBtu}{hr} * 7.6\ \frac{lb}{MMscf} * \frac{1}{1{,}020}\ \frac{scf}{Btu} * 8{,}760\ \frac{hr}{yr} * \frac{1\, ton}{2{,}000\ lb}$$

It should be noted that gas combustion-related particulate emissions are expected to be below the Lake County PM_{10} SIP Limit of 0.01 grains per dry standard cubic foot (gr/dscf).

An overall utilization factor of 97.5% is applied to calculate the limited annual potential emissions for both boilers.

If an SCR system or systems are installed, additional particulate matter emissions will be generated from the sulfur oxide emissions from the new boilers as a result of the SCRs, which chemically reduce NO_X emissions through a reaction with ammonia (NH_4). This process can produce additional

[4] Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO_2 combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO_3). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO_2 for SO_2 emission calculations.

particulate emissions through the production of ammonium sulfate ($(NH_4)_2(SO_4)$). The additional $PM_{10}/PM_{2.5}$ emissions from the boilers with SCRs are conservatively calculated by assuming 3% of the SO_X emitted by the boiler is in the form of SO_3, and that all of this SO_3 reacts to form $(NH_4)_2(SO_4)$ as shown below. This is a conservative assumption since, as discussed below, some fraction of the SO_3 emitted will react to form sulfuric acid mist.[5]

$$SO_3 + 2\ NH_3 + H_2O \Leftrightarrow (NH_4)_2(SO_4)$$

The additional $PM_{10}/PM_{2.5}$ emissions from the condensable $(NH_4)_2(SO_4)$ can be calculated using the methodology below for the duct burners with SCRs.

PM (in the form of $(NH_4)_2(SO_4)$) [lb] =

$$lb\ SO_2\ emitted * \frac{1\,mol\ SO_2}{64.06\ lb\ SO_2}\frac{3\%}{100}\frac{mol\ SO_3}{mol\ SO_2} * \frac{1\,mol\ (NH_4)_2(SO_4)}{1\,mol\ SO_3} * \frac{132.12\ lb\ (NH_4)_2(SO_4)}{1\,mol\ (NH_4)_2(SO_4)}$$

Therefore, the total $PM_{10}/PM_{2.5}$ emissions from a single new boiler are the sum of the combustion emissions and the additional emissions as a result of the SCR reaction.

E.1.11.2.5 SULFURIC ACID MIST (H_2SO_4 MIST) EMISSIONS

Combustion emissions are assumed to include some amount of SO_3, which can react to form condensable particulate matter in the form of $(NH_4)_2(SO_4)$ if ammonia is present in the flue gas. However, this SO_3 can also react with water vapor present in the stack to produce sulfuric acid mist (H_2SO_4 mist). Conservatively, BP is considering that all of the SO_3 emitted can form both condensable particulate matter and H_2SO_4 mist. Calculations for H_2SO_4 mist emissions are shown below.

$$SO_3 + H_2O \Leftrightarrow H_2SO_4$$

This reaction is temperature dependent and the fraction of SO_3, which reacts to form H_2SO_4, can be estimated using Antoine's Equation as shown in Table C.6 of Appendix C. H_2SO_4 mist emissions are conservatively calculated by assuming 3% of the SO_X emitted by the heater are in the form of SO_3, and assuming that all of the SO_3 will react to form H_2SO_4. The amount of H_2SO_4 mist emitted can be calculated using the methodology below.

[5] Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO_2 combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO_3). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO_2 for SO_2 emission calculations.

$$H_2SO_4 = lb\ SO_2\ Emitted * \frac{1\,mol\ SO_2}{64.06\,lb\ SO_2} * \frac{3\%}{100}\ \frac{mol\ SO_3}{mol\ SO_2} * \frac{1\,mol\ H_2SO_4}{1\,mol\ SO_3} * \frac{98.07\,lb\ H_2SO_4}{1\,mol\ H_2SO_4}$$

$$* 8{,}760\ \frac{hr}{yr} * \frac{1\,ton}{2{,}000\ lb}$$

E.1.11.2.6 LEAD (PB) EMISSIONS

The combustion lead emissions for the boilers are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998).

E.1.11.2.7 FUGITIVE VOC COMPONENTS

As part of the boilers project, a number of new fugitive emission components (e.g., valves and flanges) will be added. Because detailed process and instrumentation diagrams (P&IDs) are not yet available for the new units, the total number of components was estimated based on similar existing units at the refinery or similarly designed units by the same vendor. To estimate the VOC emissions increase due to the changes in fugitive emission components at the refinery, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. The gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for valves are 80%, based on a 500 ppmv leak definition for valve. The remainder of the new fugitive components achieve a 30% control efficiency from audio/visual/olfactory observations (AVO) per Texas Commission on Environmental Quality (TCEQ) Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000). As a conservative basis, all components were assumed to contain 100% VOC. The fugitive emission calculations are detailed in Appendix F with the emission calculations.

A summary of the potential emissions for this project is provided below:

	VOC (tons/yr)	NO_x (tons/yr)	PM (tons/yr)	$PM_{10}/PM_{2.5}$ (tons/yr)	CO (tons/yr)	SO_2 (tons/yr)
TOTAL	27.2	322.0	9.2	40.0	118.9	49.8

E.1.11.3 REGULATORY APPLICABILITY

E.1.11.3.1 COMPLIANCE ASSURANCE MONITORING

CAM requirements are typically triggered upon Title V permit renewal. BP Whiting received its initial Title V permit effective January 1, 2007. As such, CAM requirements could only be triggered at this stage by a significant modification to a large pollutant specific emission unit (PSEU).[6] A large PSEU is a controlled unit for which controlled potential emissions are by themselves above major source permitting thresholds.[7] Units are exempt from CAM if they already are subject to continuous monitoring requirements (e.g., as part of a MACT standard).[8] Note that the boilers do not meet the definition of a large PSEU as the boilers are subject to continuous monitoring requirements for several pollutants and have post-control emissions below major source thresholds. CAM requirements are, therefore, not applicable to the boiler project.

E.1.11.3.2 NSPS SUBPART J – PETROLEUM REFINERIES

The new boilers will be regulated under NSPS J as fuel gas combustion devices. Under these requirements, BP will be required to continuously monitor the H_2S concentration of the refinery fuel gas combusted in these boilers to demonstrate compliance with a limitation of 0.1 gr/scf H_2S in fuel gas (3-hour average).

E.1.11.3.3 NSPS SUBPART DB – INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

NSPS Db regulates emissions from industrial, commercial, and institutional steam generating units with a rated heat input capacity greater than 100 MMBtu per hour. The new boilers have a rated heat input greater than 100 MMBtu per hour and will thus be subject to the requirements of gaseous fuel combustion under NSPS Db (i.e., natural gas and waste/byproduct). Under these requirements, BP will be required to meet a NO_x limit calculated in accordance with 40 CFR 60.44b(e) or (f). Compliance with the NO_x limits will be demonstrated through installation of a continuous emission monitoring system (CEMS) for NO_x. The SO_2 emission limits will not apply per 40 CFR 60.40(b), as the boilers will be subject to 40 CFR 60, Subpart J.

E.1.11.3.4 40 CFR 63, SUBPART DDDDD – INDUSTRIAL, COMMERCIAL, AND INDUSTRIAL BOILERS AND PROCESS HEATERS

The regulations of 40 CFR 63, Subpart DDDDD have been vacated as of the time of submission of this application. IDEM has not adopted an interim regulation, and therefore the requirements of 40 CFR 63, Subpart DDDDD are not addressed in this application. Once a replacement regulation is promulgated, the boilers will be evaluated for applicability.

[6] Per 40 CFR 64.5(a).
[7] Per 40 CFR 64.1
[8] Per 40 CFR 64.2

E.1.11.3.5 NSPS Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries

New fugitive components installed to supply refinery fuel gas for the boilers as part of this project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG. Note that NSPS GGG requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.11.3.6 40 CFR 61 NESHAP

The NESHAP subparts found in 40 CFR 61 are pollutant specific regulations applicable to certain sources of HAP. No Part 61 NESHAPs apply to this project since this project only involves fuel combustion.

E.1.11.3.7 40 CFR 63, Subpart CC – Petroleum Refineries

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Applicable components constructed as part of the boilers project will also be subject to these requirements. Note that an affected facility under 40 CFR 63 Subpart CC is defined as the entire refinery, therefore, the boiler project will not constitute a "reconstruction" of the affected source. As such, new units constructed as part of the boilers project will be subject to the same existing source standards already applicable to the refinery.

E.1.11.3.8 326 IAC 1-6-3 – Preventive Maintenance Plans

Preventive Maintenance Plans (PMPs) are required for any source that requires a permit. As such, BP Whiting will develop and maintain PMPs for the boilers and any associated control equipment.

E.1.11.3.9 326 IAC 1-7 – Stack Height Provisions

The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO_2 or PM emissions in levels greater than 25 tpy. The provisions of this rule do not apply to the boilers since potential emissions of PM and SO_2 are less than 25 tpy for each boiler.

E.1.11.3.10 326 IAC 3-5 – Continuous Monitoring of Emissions

The boilers will be subject to continuous emissions monitoring requirements in this rule.

E.1.11.3.11 326 IAC 5-1-2 – Opacity Limits

This rule requires facilities in Lake County to meet the following facility-wide opacity limits:

- Opacity shall not exceed 20% in any six-minute period, and
- Opacity shall not exceed 60% in any cumulative total of fifteen (15) minutes in any 6-hour average period.

The two new boilers are subject, and will comply, with the opacity limits in this rule.

E.1.11.3.12 326 IAC 6.8-1-2 –PARTICULATE LIMITS

The new boilers will be subject to the provisions of this rule, specifically paragraph (b)(3), which limits PM emissions from combustion of gaseous fuels to 0.01 grains per dry standard cubic foot (gr/dscf).

E.1.11.3.13 326 IAC 7-4.1-1–SO_2 EMISSION LIMITATIONS

This rule is not applicable since the potential emissions for each boiler will be less than 25 tpy of SO_2. BP is requesting a limit of less than 25 tpy SO_2 for the emissions of each boiler. Compliance will be achieved by reducing the total sulfur content of the fuel gas and/or blend of fuel gas and natural gas.

E.1.11.3.14 326 IAC 8-1-6 – VOC RULES, BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

In this rule, IDEM requires every new unit that has potential emissions greater than 25 tpy of VOC to perform a BACT review. Since each of the new boilers does not have potential emissions greater than 25 tpy of VOC, this rule is not applicable.

E.1.11.3.15 326 IAC 10-4-2 –NOX BUDGET TRADING PROGRAM

The NO_x Budget Trading Program is applicable to large affected units. The new boilers will have a rated capacity of greater than 250 MMBtu per hour, which qualifies them as large affected units under this rule. However, since the boilers will most likely not operate until 2009, the boilers will be subject to 326 IAC 24-3 per 326 IAC 10-14-16 since 326 IAC 10-4-2 does not apply in the ozone seasons in 2009 and later.

E.1.11.3.16 326 IAC 24-3 – CLEAN AIR INTERSTATE RULE NOX OZONE SEASON TRADING PROGRAM

The Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program is applicable to large affected units. The new boilers will have a rated capacity of greater than 250 MMBtu per hour, which qualifies them as large affected units under this rule. BP will submit a NO_x budget permit application for the three new boilers at least 270 days prior to the later of January 1, 2009 or commencement of operation of the boilers per 326 IAC 24-3-7(b)(1).

E.1.12 3 SPS SCRs

E.1.12.1 PROJECT DESCRIPTION

The proposed modification includes the construction of new gas-fired duct burners and selective catalytic reduction (SCR) systems for the No.3 Stanolind Power Station (3 SPS) Boilers #1, 2, 3, 4, and 6. This project is being undertaken for the purposes of reducing NO_x emissions at the refinery's existing 3SPS power house. The SCR systems (one SCR system for each boiler) will help the Whiting Refinery meet NO_x emission reductions to satisfy consent decree requirements.[9] The duct burners are necessary to increase the temperature of the exhaust gas so as to prevent fouling in the SCR system. Since the purpose of this project is to reduce emissions, it will not result in any throughput/production increases or associated emission increases for the refinery.

In order to increase the temperature of the exhaust gas from the boilers at the 3SPS power house, five (5) new directly-fired duct burners (i.e., one for each boiler) rated at 41 MMBtu/hr each will be installed at the 3SPS power house. NO_x emissions from these new duct burners will be controlled with a combination of Low-NO_X Burners and the SCRs. The addition of Low-NOx Burners is expected to result in lower CO emissions than current levels. Since the duct burners will be constructed before the refinery fuel gas treatment system consistently provides refinery fuel gas with a total sulfur content of 80 ppmv, the potential emissions were calculated assuming that the duct burners will burn refinery fuel gas with a TRS content of 159 ppm (i.e., equivalent to NSPS J H_2S limit). A simplified process flow diagram for the new SCR systems that will be installed is included in this Appendix.

Aqueous ammonia storage drums storing 19.1% NH_3 will be installed. Electric heaters will be used to vaporize the ammonia to supply ammonia to the SCR systems. The ammonia storage drums are exempt per 326 IAC 2-1.1-3(e)(39)(B) and are trivial activities per 325 IAC 2-7-1(40)(J)(ii), and the electric heaters are exempt and are a trivial activity per 326 IAC 2-7-1 (40)(J)(ii).

Modifications to existing fugitive components will be made and new fugitive components will be added as part of the 3SPS SCR project. These components include flanges and valves in refinery fuel gas service.

The proposed project includes some changes for the equipment associated with the 3 SPS boilers; however, the existing boilers will not be modified or reconstructed as a result of this project per the NSPS provisions or the major NSR provisions. The boilers share an induced draft (ID) fan that will be replaced as part of this project to account for the increase in pressure drop that will occur through the SCR systems. The boilers are not currently limited by the size of the ID fan. Furthermore, the new ID fan will not allow the boilers to

[9] United States, et. al. v. BP Exploration & Oil, et. Al.; Northern District of Indiana, Hammond Division; Civil Action No. 2:96 CV 095 RL.

fire more fuel gas or produce more steam than the current ID fan; therefore, the new ID fan will neither result in a modification to the existing boilers nor an increase in emissions.

The existing control equipment including the Low-NO_X burners, overfire air (OFA) and Flue Gas Recirculation (FGR) on the boilers will be replaced with the following new control equipment package: new conventional burners that are similar to the design that was used in the boilers in the past before changes that were intended to achieve reductions for the consent decree were made and the SCR systems. The current NO_x control system, especially OFA, causes flame impingement concerns and has not achieved the desired reductions in NO_X emissions. Per 40 CFR 60.14(e)(5), the change in control equipment will not result in a modification for 40 CFR 60, Subpart Db since the primary purpose of the replacement is to reduce emissions of NO_X, the pollutant to which the NSPS standard applies.

Currently, BP has been using reduced OFA and higher oxygen concentrations to alleviate the flame impingement issues associated with the existing control package. With the replacement of the control package, BP will no longer need to use increased oxygen concentrations to prevent the flame impingement issues. With the installation of the new control equipment package CO emissions will decrease since it will be easier to control excess air. The boilers will not produce more steam, and the heat input capacity will not increase as a result of the installation of the new control package; therefore, the control package replacements will neither result in modifications to the existing boilers nor an increase in emissions for NSPS or NSR purposes.

A steam economizer will be installed to capture heat from the exhaust of the SCR systems and pre-heat the boilers' feed water. Currently, steam produced by the boilers is used to preheat the boilers' feed water. The installation of the economizer will potentially allow the steam that would have been used to preheat the boilers' feed water to be used elsewhere; however, it will not allow debottlenecking of the steam supply to the refinery since the refinery is not currently steam-limited and the amount of incremental steam that was used for preheating the boilers' feed water could currently be produced by any of the other steam sources for the Whiting Refinery (e.g., 1 SPS, 3 SPS, or Whiting Clean Energy). In addition, new boilers (as discussed in Section 3.7) are being added to address the additional future steam demand from the shutdown of 1 SPS, the potential loss of the Whiting Clean Energy steam, and the CXHO project.

Since none of the proposed changes will result in modifications to or debottlenecking of the 3 SPS boilers, the boiler emissions were not considered to be part of this project for the purposes of permitting applicability. The potential SO_2 emissions from the boilers were considered with respect to the conversion of the SO_2 emissions to additional condensable PM as a result of the installation of the SCR systems[10]. In addition, emissions decreases of CO were quantified.

[10] The ammonia injected as part of the SCR system may react with some portion of SO_x emissions from the boilers to form additional PM emissions.

BP will test the existing CO analyzers for the 3 SPS boilers for certification as CEMS for tracking total annual CO emissions from each boiler/duct burner stack.

BP is requesting an annual limit on total fuel input for all five boilers at 96.5% of the total combined heat input capacity (i.e., 24,303,525 MMBtu/yr) and on the total fuel input for all five duct burners (i.e., 1,732,947 MMBtu/yr) to allow flexibility for maintenance outages.

E.1.12.2 EMISSIONS CALCULATIONS

E.1.12.2.1 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

The annual VOC emissions from combustion for all new duct burners are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) as is presented in the equation below.[11]

$$Emissions(tpy) = D * VOC\ EF_{AP-42} * \frac{1}{HHV_{AP-42}} * 8{,}760\ \frac{hr}{yr} * \frac{1\ ton}{2{,}000\ lb}$$

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
VOC EF_{AP-42} = AP-42 emission factor (lb/MMscf)
HHV_{AP-42} = natural gas higher heating value assumed by AP-42 (MMBtu/MMscf)

For example, the VOC emissions from the one duct burner are:

$$VOC\ (tpy) = 41\ \frac{MMBtu}{hr} * 5.5\ \frac{lb}{MMscf} * \frac{1}{1{,}020}\ \frac{MMscf}{MMBtu} * 8{,}760\ \frac{hr}{yr} * \frac{1\ ton}{2{,}000\ lb}$$

$$VOC\ (tpy) = 0.97\ tpy$$

An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

Detailed emission calculations are provided in the emission calculations sheet provided in Appendix F.

E.1.12.2.2 NITROGEN OXIDE (NO_X) AND CARBON MONOXIDE (CO) EMISSIONS

The NO_X and CO emissions for the new duct burners are based on vendor guaranteed emission rates.[12] These are detailed in Table 3.2.

[11] Process heaters at the BP Whiting refinery fire mainly refinery fuel gas. Refinery fuel gas is very similar in composition to natural gas, with the possible exception of its sulfur content. AP-42 emission factors for natural gas combustion are a good representation of refinery fuel gas combustion emissions for all criteria pollutants except SO_2 and it is common practice in the refining industry to utilize these factors.

[12] Each duct burner will exhaust through the same stack as the associated boiler; therefore, BP is requesting a combined annual total limit on CO emissions from the duct burners and boilers based on a 12-month rolling average. As

TABLE E-2. NO_X AND CO EMISSION RATES

Unit	NO_X Emission Rate (lb/MMBtu)	NO_X Control	CO Emission Rate (lb/MMBtu)	CO Control
Duct burner	0.05	Controlled – Low NO_X Burners	0.02	Good Combustion Practices

The methodology to calculate NO_X and CO emissions is presented in the equation below.

$$NO_X \ \ Emissions(tpy) = D * NO_X \ \ EF * 8{,}760 \frac{hr}{yr} * \frac{1\,ton}{2{,}000\,lb}$$

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
NO_x EF = NOx emission factor (lb/MMBtu)

For example, the uncontrolled NO_X emissions from the Duct Burner are:

$$NO_X \ \ (tpy) = 41 \frac{MMBtu}{hr} * 0.05 \frac{lb}{MMBtu} * 8{,}760 \frac{hr}{yr} * \frac{1\,ton}{2{,}000\,lb}$$
$$NO_X \ \ (tpy) = 8.98\,tpy$$

Since the duct burners' exhaust will be routed through the SCR systems, a control efficiency of 95% is applied to the uncontrolled emissions. The overall emission rate from the duct burners and 3 SPS boilers combined will be 0.02 lb/MMBtu.

An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

E.1.12.2.3 SULFUR DIOXIDE (SO_2) EMISSIONS

SO_2 emissions from the duct burners can be calculated using the equation below.

$$SO_2 \ \ Emissions(tpy) = D * SO_2 \ \ EF * \frac{1}{HHV_F} * 8{,}760 \frac{hr}{yr} * \frac{1\,ton}{2{,}000\,lb}$$

Where,
D = Maximum Heat Input Capacity (MMBtu/hr)
HHV_F = Higher heating value of refinery fuel gas (MMBtu/MMscf)
SO_2 EF = SO_2 emission factor (lb/MMscf)

discussed previously, BP will test the existing CO analyzers for certification as CEMS such that annual emissions can be tracked with the CEMS. The requested NO_x limit is addressed in the regulatory applicability section of this application.

The emission factor (SO_2 EF) in the above equation is a function of the total sulfur concentration in the fuel gas and can be calculated from the Ideal Gas Law as follows:

$$SO_2\ EF = \frac{C * MW * P}{R * T}$$

Where,
C = Refinery fuel gas total sulfur concentration (ppm)
MW = Molecular Weight (lb/lbmol)
P = Pressure (psia)
R = Ideal Gas Constant (psia*ft^3/(lbmol*R))
T = Temperature (R)

An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

As part of the 3SPS SCR project, the maximum total sulfur content in the fuel gas is projected to be no more than 159 ppmv. It is assumed that 1 mole of sulfur compounds in the fuel gas will yield 1 mole of SO_2 emissions. Therefore, the SO_2 emission factor can be calculated in accordance with the equation below:

$$SO_2\ EF = (159\,ppm) * (\frac{1\,lbmol\ SO_2}{1\,lbmol\ total\ sulfur}) * (\frac{64.06\,lb\ SO_2}{1\,lbmol\ SO_2}) * \frac{14.7\ psi}{(10.73\,\frac{psi \cdot ft^3}{lbmol \cdot R}) * (67.7 + 460)^o\,R}$$

$$SO_2\ EF = 26.44\,\frac{lb\ SO_2}{MMscf}$$

The projected future actual annual average fuel gas higher heating value is 1203.3 MMBtu/MMscf.

Note that, for the purpose of estimating SO_2 emissions, BP is assuming that all sulfur oxides are emitted in the form of SO_2.[13] This assumption is conservative, since, as discussed below, as much as 3% of the total sulfur oxides emitted will be in the form of SO_3, which will be emitted as either condensable PM or sulfuric acid mist.

[13] Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO_2 combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO_3). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO_2 for SO_2 emission calculations.

E.1.12.2.4 PARTICULATE MATTER ($PM/PM_{10}/PM_{2.5}$) EMISSIONS

The combustion-related $PM_{10}/PM_{2.5}$ emissions for all the duct burners are calculated using the total PM emission factor from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). The PM emissions are calculated using the filterable PM emission factor.

For example, the annual $PM_{10}/PM_{2.5}$ emissions from one duct burner are:

$$PM_{10} / PM_{2.5} = 41\ \frac{MMBtu}{hr} * 7.6\ \frac{lb}{MMscf} * \frac{1}{1{,}020}\ \frac{scf}{Btu} * 8{,}760\ \frac{hr}{yr} * \frac{1\ ton}{2{,}000\ lb}$$

$$PM_{10} / PM_{2.5} = 1.34\ tpy$$

It should be noted that gas combustion-related particulate emissions are expected to be below the Lake County PM_{10} SIP Limit of 0.03 grains per dry standard cubic foot (gr/dscf).

Additional particulate matter emissions will be generated from the sulfur oxide emissions from the new duct burners as a result of the SCRs, which chemically reduce NO_X emissions through a reaction with ammonia (NH_4). This process can produce additional particulate emissions through the production of ammonium sulfate ($(NH_4)_2(SO_4)$). The additional $PM_{10}/PM_{2.5}$ emissions from the duct burners with SCRs are conservatively calculated by assuming 3% of the SO_X emitted by the heater is in the form of SO_3, and that all of this SO_3 reacts to form $(NH_4)_2(SO_4)$ as shown below. This is a conservative assumption since, as discussed below, some fraction of the SO_3 emitted will react to form sulfuric acid mist.[14]

$$SO_3 + 2\ NH_3 + H_2O \Leftrightarrow (NH_4)_2(SO_4)$$

The additional $PM_{10}/PM_{2.5}$ emissions from the condensable $(NH_4)_2(SO_4)$ can be calculated using the methodology below for the duct burners with SCRs.

PM (in the form of $(NH_4)_2(SO_4)$) [lb] =

$$lb\ SO_2\ emitted * \frac{1\ mol\ SO_2}{64.06\ lb\ SO_2}\ \frac{3\%}{100}\ \frac{mol\ SO_3}{mol\ SO_2} * \frac{1\ mol\ (NH_4)_2(SO_4)}{1\ mol\ SO_3} * \frac{132.12\ lb\ (NH_4)_2(SO_4)}{1\ mol\ (NH_4)_2(SO_4)}$$

[14] Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO_2 combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO_3). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO_2 for SO_2 emission calculations.

Therefore, the total $PM_{10}/PM_{2.5}$ emissions from a single new duct burner are the sum of the combustion emissions and the additional emissions as a result of the SCR reaction.

An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

E.1.12.2.5 SULFURIC ACID MIST (H_2SO_4 MIST) EMISSIONS

As discussed, combustion emissions are assumed to include some amount of SO_3, which can react to form condensable particulate matter in the form of $(NH_4)_2(SO_4)$ if ammonia is present in the flue gas. However, this SO_3 can also react with water vapor present in the stack to produce sulfuric acid mist (H_2SO_4 mist). Conservatively, BP is considering that all of the SO_3 emitted can form both condensable particulate matter and H_2SO_4 mist. Calculations for H_2SO_4 mist emissions are shown below.

$$SO_3 + H_2O \Leftrightarrow H_2SO_4$$

H_2SO_4 mist emissions are conservatively calculated by assuming 3% of the SO_X emitted by the heater are in the form of SO_3. The amount of H_2SO_4 mist emitted can be calculated using the methodology below.

$$H_2SO_4 = lb\ SO_2\ Emitted * \frac{1\,mol\ SO_2}{64.06\,lb\ SO_2} * \frac{3\%}{100}\frac{mol\ SO_3}{mol\ SO_2} * \frac{1\,mol\ H_2SO_4}{1\,mol\ SO_3} * \frac{98.07\ lb\ H_2SO_4}{1\,mol\ H_2SO_4}$$

$$* 8{,}760\ \frac{hr}{yr} * \frac{1\,ton}{2{,}000\ lb}$$

An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

E.1.12.2.6 LEAD (PB) EMISSIONS

The combustion lead emissions for all new duct burners are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). An overall utilization factor of 96.5% is applied to calculate the limited annual potential emissions for the duct burners.

E.1.12.2.7 NEW SELECTIVE CATALYTIC REDUCTION UNITS

Under the 3SPS Project, BP Whiting plans to install, at its boilers at the 3SPS Power House, SCR systems (one for each boiler). Additional PM emissions from the 3SPS SCR are a function of the SO_2 to SO_3 conversion efficiency which has been conservatively assumed to be 3%, as well as a function of the predicted emissions from the 3SPS boilers.

E.1.12.2.8 PARTICULATE MATTER ($PM/PM_{10}/PM_{2.5}$) EMISSIONS

As discussed for the duct burners, the $PM_{10}/PM_{2.5}$ emissions from the 3SPS SCR are calculated based on the maximum boiler capacity and projected actual SO_2 emissions from the 3SPS Boilers. Note that the projected total sulfur concentration of 147 ppm (maximum measured concentration of total sulfur at BP Whiting), was used for calculating the potential boiler SO_2 emissions since the boiler is an existing unit. An overall utilization factor of 96.5% is also applied.

E.1.12.2.9 FUGITIVE VOC COMPONENTS

As part of the 3SPS SCR project, a number of new fugitive emission components (e.g., valves and flanges) will be added. Because detailed process and instrumentation diagrams (P&IDs) are not yet available for the new units, the total number of components was estimated based on similar existing units at the refinery or similarly designed units by the same vendor. To estimate the VOC emissions increase due to the changes in fugitive emission components at the refinery, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. The gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for valves are 80%, based on a 500 ppmv leak definition for valve. The remainder of the new fugitive components achieve a 30% control efficiency from audio/visual/olfactory observations (AVO) per Texas Commission on Environmental Quality (TCEQ) Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000). As a conservative basis, all components were assumed to contain 100% VOC. The fugitive emission calculations are detailed in Appendix E with the emission calculations.

A summary of the total project emissions is provided below.

	VOC (tons/yr)	NO_x (tons/yr)	PM (tons/yr)	$PM_{10}/PM_{2.5}$ (tons/yr)	CO (tons/yr)	SO_2 (tons/yr)
TOTAL	5.6	2.2	1.6	22.9	-106.7	19.0

E.1.12.3 REGULATORY APPLICABILITY

E.1.12.3.1 COMPLIANCE ASSURANCE MONITORING (CAM)

CAM requirements are typically triggered upon Title V permit renewal. As such, CAM requirements could only be triggered at this stage by a significant modification to a large pollutant specific emission unit (PSEU). A large PSEU is a controlled unit for which controlled potential emissions are by themselves above major source permitting thresholds. Note that the duct burners are not large PSEUs. Units are exempt from CAM if they already are subject to continuous monitoring requirements (e.g., as part of a MACT standard). Note that the boilers are not being modified. Also boilers are subject to continuous monitoring requirements for NO_x. CAM requirements are, therefore, not applicable to the 3SPS project.

E.1.12.3.2 NSPS Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries

New fugitive components installed to supply refinery fuel gas for the duct burners at 3SPS as part of the 3SPS SCR project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG. Note that NSPS GGG requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.12.3.3 NSPS Subpart J – Petroleum Refineries

NSPS J regulates emissions from fuel gas combustion devices. All new duct burners under the 3SPS SCR project will be subject to the requirements for fuel gas combustion devices under NSPS J. Under these requirements, BP will be required to continuously monitor the H_2S concentration of the refinery fuel gas combusted in these burners to demonstrate compliance with a limitation of 0.1 gr/scf H_2S in fuel gas (3-hour average).

E.1.12.3.4 NSPS Subpart VV – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

New fugitive components installed at to supply refinery fuel gas for the duct burners at 3SPS as part of the 3SPS SCR project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG. Note that NSPS GGG requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.12.3.5 40 CFR 61 NESHAP

The NESHAP subparts found in 40 CFR 61 are pollutant specific regulations applicable to certain sources of HAP. No Part 61 NESHAPs apply to this project since this project only involves fuel combustion and SCR systems.

E.1.12.3.6 40 CFR 63, Subpart CC – Petroleum Refineries

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. Applicable components constructed as part of the 3SPS SCR project will also be subject to these requirements. Note that an affected facility under 40 CFR 63 Subpart CC is defined as the entire refinery, therefore, the 3SPS SCR project will not constitute a “reconstruction” of the affected source. As such, new units constructed as part of the 3SPS SCR project will be subject to the same existing source standards already applicable to the refinery.

E.1.12.3.7 40 CFR 63, Subpart DDDDD – Industrial, Commercial, and Industrial Boilers and Process Heaters

The duct burners are not subject to 40 CFR 63, Subpart DDDDD since they are directly fired.

E.1.12.3.8 326 IAC 1-6-3 – Preventive Maintenance Plans

Preventive Maintenance Plans (PMPs) are required for any source that requires a permit. As such, BP Whiting will develop and maintain PMPs for the SCRs as part of the 3SPS SCR Project.

E.1.12.3.9 326 IAC 1-7 – Stack Height Provisions

The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO_2 or PM emissions in levels greater than 25 tpy. Each duct burner and SCR system does not have the potential to emit SO_2 or PM emissions at levels greater than 25 tpy; therefore, the provisions of this rule do not apply.

E.1.12.3.10 26 IAC 3-5 – Continuous Monitoring of Emissions

The boilers at BP Whiting are currently subject to continuous emissions monitoring requirements in this rule and will continue to meet the requirements of the rule for the boiler stacks after the SCR systems are installed. It should be noted that since the duct burners are direct-fired, the duct burner emissions will also be included in the continuously monitored emissions.

E.1.12.3.11 326 IAC 5-1-2 – Opacity Limits

This rule requires facilities in Lake County to meet the following facility-wide opacity limits:

Opacity shall not exceed 20% in any six-minute period, and
Opacity shall not exceed 60% in any cumulative total of fifteen (15) minutes is any 6-hour average period.

BP Whiting is subject, and will comply, with the facility-wide opacity limits in this rule.

E.1.12.3.12 326 IAC 6.8-1-2, 6.8-2-6 – Lake County PM/PM_{10} Emission Requirements

BP Whiting is subject to the PM limits in these rules. Specifically, PM emissions from the new duct burners constructed as part of the 3SPS SCR Project will be limited to 0.03 gr/dscf, as required by 326 IAC 6.8-1-2.

E.1.12.3.13 326 IAC 7-1.1-1, 7-2, 7-4.1-3 – Lake County SO_2 Emission Limitations

It should be noted that the new units being installed as part of the 3SPS SCR project will not be subject to the limitations per 326 IAC 7-4.1-1 since the potential SO_2 emissions from these units are below the 25 tpy applicability threshold specified in 326 IAC 7-1.1-1.

E.1.12.3.14 326 IAC 8-1-6 – VOC Rules, Best Available Control Technology (BACT)

In this rule, IDEM requires every new unit that has potential emissions greater than 25 tpy of VOC to perform a BACT review. Since none of the 3SPS SCR project new units has potential emissions greater than 25 tpy of VOC, this rule is not applicable.

E.1.12.3.15 326 IAC 8-4-8, 8-4-9 – VOC Rules, Petroleum Sources – Leak Monitoring and Detection

BP Whiting is subject to the leak monitoring and detection requirements in these rules.

E.1.12.3.16 326 IAC 10-4-2 –NO_X Budget Trading Program

The NO_x Budget Trading Program is applicable to large affected units.

Per 326 IAC 10-4-2(77),
(71) “Unit” means a fossil fuel-fired:
(A) stationary boiler;
(B) combustion turbine; or
(C) combined cycle system.

No new boilers, turbines, or combined cycle systems will be constructed as part of the 3SPS SCR project. Note that a number of duct burners will be constructed as part of this project, but duct burners do not meet the definition of boiler per 326 IAC 10-4-2(77):

(6) “Boiler” means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other heat transfer medium.

The duct burners are used to provide direct heat to the exhaust and not to heat a heat transfer medium such as steam. As such, duct burners are not subject to this program.

The Whiting Refinery operates the 1SPS and 3SPS boilers in accordance with the applicable NO_x Budget Program requirements for those units.

E.1.12.4 CONSENT DECREE REQUIREMENTS

BP is required to reduce NO_X emissions in accordance with the consent decree.[15] Paragraph 15.E. of the consent decree requires that BP calculate the NO_X emissions reductions based on permit allowable emissions. As a result, BP is requesting a 365-day rolling average permit limit of 0.02 lb/MMBtu for the 3 SPS boilers such that BP Whiting can use 0.02 lb/MMBtu as the allowable emissions from the 3 SPS boilers for the consent decree calculations. In addition, Paragraph 15.H. of the consent decree requires that, within ninety (90) days of the date of installation of each control technology for which BP seeks recognition under Paragraphs 15.C. and E, BP shall conduct an initial performance test for NO_x and CO.

E.1.13 STORAGE TANK 3637

E.1.13.1 PROJECT DESCRIPTION

BP Whiting proposes to reconstruct the existing storage tank 3637, located in the Lake George Tank Field. This tank was originally constructed in 1956 as an external floating roof tank (mechanical shoe primary seal and a rim mounted secondary seal) with a capacity of 6,353,000 gallons. The tank is currently listed in Section D.27 of the existing Title V permit.

The modifications to the existing tank include installation of a new floating roof (mechanical shoe primary seal and a rim mounted secondary seal) and an external dome; and minor piping installations and modifications. Storage tank 3637 has been out of service since 2000. The tank will be used to store heavy ultraformate (HUF) and xylene.

E.1.13.2 EMISSION CALCULATIONS

The future potential emissions for the proposed project were calculated using USEPA Tanks 4.09d software program. Since the tank has been out of service since 2000, the baseline emissions were assumed to be 0 tons/year. The following data was used in the calculations:

1. Maximum estimated throughput of 229,950,000 gallons per year,

[15] United States, et. al. v. BP Exploration & Oil, et. al.; Northern District of Indiana, Hammond Division; Civil Action No. 2:96 CV 095 RL.

2. Properties of Xylenes, mixed isomers, and
3. Detailed tank fittings and other parameters required for domed external floating roof tanks.

In addition, new fugitive components will be added for piping associated with this project. The material is considered a light liquid. To estimate the VOC emissions increase due to the new fugitive emission components, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. As detailed in Appendix C (Tables C.29 through C.43 and C.63), the gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for pumps and valves are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv leak definition for pumps. The assumptions used in the emissions calculations are documented in the detailed calculations provided in Appendix E.

The future potential emissions for the proposed storage tank reconstruction are shown below:

Source	VOC (lbs/year)	VOC (tons/year)
3637 Tank Emissions	401.16	0.20

E.1.13.3 REGULATORY APPLICABILITY

E.1.13.3.1 40 CFR PART 60 – NEW SOURCE PERFORMANCE STANDARDS (NSPS):

The proposed modifications to storage tank 3637 will meet the definition of reconstruction as outlined in 40 CFR 60.15(b) for the purposes of 40 CFR 60, Subpart Kb. Per 40 CFR 60.15(d) the following information is provided:

(1) Name and address of the owner or operator. *See application.*

(2) The location of the existing facility. *Lake George Tank Field*

(3) A brief description of the existing facility and the components which are to be replaced. *See Project Description above.*
.
(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment. *See Project Description above.*

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility. *Fixed capital cost of the replacements = $2,227,900; Fixed capital cost of constructing a comparable new facility = $2,500,000*

(6) The estimated life of the existing facility after the replacements. *The estimated life of the reconstructed tank depends on the corrosion rate of the*

tank and periodic inspections. In the past, tanks in similar service have been used for approximately 30 years.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements. *No economic or technical limitations exist. The tank will be built in compliance with 40 CFR 60, Subpart Kb.*

E.1.13.3.2 40 CFR Part 63 – National Emissions Standards For Hazardous Air Pollutants for Source Categories:

Storage tank 3637 may be considered a "storage vessel" under the Refinery MACT. However, pursuant to 40 CFR 63.640(n)(1), "a Group 1 or Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section."

E.1.13.3.3 Rule 326 IAC 8-4-3 Petroleum Liquid Storage Facilities:

Storage tank 3637 will be subject to 326 IAC 8-4-3, as the storage capacity is greater than 39,000 gallons and the true vapor pressure of the volatile organic liquid stored will be greater than 1.52 psia.

E.1.13.3.4 Rule 326 IAC 8-9 Volatile Organic Liquid Storage Vessels:

Storage tank 3637 is not subject to the requirements of 326 IAC 8-9 because this storage tank is subject to 40 CFR 60, Subpart Kb. Storage tanks subject to the provisions of 40 CFR 60, Subpart Kb are exempt from 326 IAC 8-9 by 326 8-9-2(8).

E.1.14 FCU 600 TAR

E.1.14.1 Project Description

During the next FCU 600 TAR, the following modifications will be made:

- The main fractionator overhead condensers will be replaced with larger exchangers and the slurry system and pump around systems will be repaired to fit for purpose (instrumentation improvements). Two unit pumps will be replaced with larger capacity pumps (J-6/J-8).
- FCU Flare tip will be replaced in kind.
- Soot blowers will be added to the SCR.

Note that no physical changes are being made to the FCU 600 regenerator as part of this project. This information has been provided since the FCU 600 is one of the modified units for the CXHO project.

E.1.14.2 EMISSION CALCULATIONS

E.1.14.2.1 FUGITIVES

Additional fugitive components will be added as part of this project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

A summary of the estimated VOC emissions associated with this project is provided below. Refer to Appendix E for detailed calculations.

	VOC (tons/yr)
TOTAL	0.3

E.1.14.3 REGULATORY APPLICABILITY

E.1.14.3.1 40 CFR PART 60 – NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

A formal analysis has not yet been conducted for NSPS GGG in accordance with 40 CFR 60.590(c) and 40 CFR 60.14. Upon completion of final design specifications, BP will review and determine the applicability of Subpart GGG.

E.1.14.3.2 NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components in light or heavy liquid service that are installed as part of this project will be subject to the Leak Detection and Repair (LDAR) requirements of 40 CFR 63, Subpart CC. Note that 40 CFR 63, Subpart CC requirements incorporate by reference the LDAR requirements of NSPS VV.

E.1.14.3.3 40 CFR PART 60 – NSPS SUBPART J – PETROLEUM REFINERIES

NSPS J regulates emissions from fuel gas combustion devices. The FCU Flare is not currently subject to the requirements for fuel gas combustion devices under NSPS J. Since the FCU flare tip will be replaced in kind and there will not be an emissions increase as a result of replacing the flare tip, the FCU Flare will not be modified as part of this project; therefore, these requirements will not apply. A formal analysis will be conducted once the design has been finalized.

E.1.14.3.4 40 CFR PART 63 – MACT SUBPART CC – PETROLEUM REFINERIES

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements. The applicable components constructed as part of the FCU 600 TAR will be subject to these requirements.